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Oxycombustion in pulverized coal-fired boiler: a promising technology for CO_2 capture

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ABSTRACT

A promising technology that enables CO_2 capture from pulverized coal-fired power plants is described. The technology involves the replacement of the combustion air by pure oxygen diluted with recirculated flue gases, and is referred to as oxycombustion process. The resulting CO_2/O_2 oxidizer provides a high flexibility for temperature and flowrate control inside the boiler. Therefore, both retrofit and new boiler applications are envisioned. The economics of the oxycombustion process have been assessed and compared to that of the same capacity air-blown coal-fired boiler equipped with amine (MEA) scrubber for carbon capture. Both capture technologies result in increased cost of electricity. However, this increase is expected to be at least 30% lower using O_2/CO_2 technology than using MEA system. The oxycombustion process leads to approximately \$20/ton CO_2 avoided, while MEA process requires more than \$40/ton CO_2. The main results of experimental tests performed on a pilot-scale boiler are also presented. Low-sulfur sub-bituminous coal was burned and the reported results highlight the characteristics of oxygen-fired mode versus air-fired mode. 70% NO_x emission reduction has been observed, and emission level as low as 0.08 lb / 10^6 Btu has been measured. The flue gas flow rate has been reduced by 80%. Oxycombustion theoretically results in 95% of CO_2 content in the flue gases. 80% CO_2 content in the flue gas has been measured so far due to air-infiltration. Further investigations are in progress to reduce the air-infiltration and provide cost-effective flue gas purification technologies. It is concluded that the oxycombustion technology represents a cost-effective and technically viable solution for CO_2 capture from coal-fired power plants.

INTRODUCTION

Fossil fuel combustion is the major contributor of increased Greenhouse Gas (GHG) emissions. About one third of carbon emissions in the United States come from power plants, one third from transportation and the remaining one third from industrial, commercial and residential sources. As fossil fuels continue to be the dominant fuel source and electricity generation is expected to grow, reducing carbon emissions by capturing and sequestering CO_2 from energy industries is vital.

Current annual U.S GHG emissions are 12% higher than they were in 1992 and it is projected by the Energy Information Administration (EIA) that CO_2 emissions will increase by additional 34% over the next 20 years [1]. Coal provides more than 50% of the United States electricity. States like Indiana and Kentucky produce more than 95% of the electricity from coal fired power plants. Coal is an abundant and cheap fuel source in US with an estimated supply for the next 250 years. Projections show that more than 50% of the nation's electricity will be supplied from coal at least in the next 20 years. Hence, coal will continue to be a prime source for electricity generation.

Numerous programs are being carried out by DOE and many private organizations promoting clean coal technologies such as FutureGen, Clean Coal Power Initiative, Vision 21 power plant etc. The goal of these DOE programs is to decrease the existing sequestration costs from currently estimated level of \$100 to \$300/ton of carbon avoided down to \$10/ton of carbon avoided by 2015. As coal fired power plants are the largest single point emitters of green house gases, there is a compelling need to deploy new and retrofit technologies to capture and sequester CO_2.

CO_2 capture cost represents around 75% of the total capture, transportation and sequestration costs [9]. The flue gas exiting a conventional air/coal power plant contains only 10% to 15% CO_2 by volume. The balance is mostly made of nitrogen N_2. Existing capture technologies to recover CO_2 from combustion exhaust, also known as post-combustion technologies - like amine scrubbing - are expensive for CO_2 emission reduction applications. In order to effectively capture the CO_2 from combustion exhaust, one option is separating N_2 from O_2 in the air prior to the combustion. In that case, the flue gas will be mainly composed of sequestration ready CO_2, along with easily condensable water. As combustion with pure oxygen yields very high temperatures, incoming combustion O_2 is diluted with recirculated flue gases. Desired temperature and flow profiles inside the boiler are thus maintained. This process of combusting the fuel in O_2-CO_2 environment, thanks to flue gas recirculation (FGR), is commonly referred to as 'Oxycombustion with recirculation' or simply 'oxycombustion', or 'O_2-CO_2 Combustion'. This paper describes the oxycombustion process, and provides detailed economical assessment of the technology and its comparison to the amine scrubbing (Monoethanolamine or MEA) technology. Experimental results obtained from pilot-scale pulverized coal fired boiler are also presented. Both retrofit and new plant cases are conceived.

OBJECTIVES

In partnership with the U.S. Department of Energy's National Energy Technology Laboratory, Air Liquide has teamed with The Babcock & Wilcox Company (B&W) and Illinois States Geological Survey (ISGS) to develop and optimize the oxycombustion of coal process. This efficient and cost-effective approach will provide new plants and existing coal-fired fleet with improved environmental performances. The main objectives of this project are as follow

(1) Perform an economical feasibility study, comparing combustion modifications via oxycombustion approach with alternate technologies such as MEA,

(2) Demonstrate the feasibility and measure the performances of the oxycombustion technology with flue gas recirculation on coal-fired pilot-scale boiler.

O_2-CO_2 COMBUSTION

Separating N_2 from O_2 in the air has significant advantages apart from obtaining CO_2 rich flue gas. As these coal fired power plants yield various pollutants such as NO_x, SO_2, Hg etc, and are facing stringent environmental regulations, measures have to be taken to limit the emission of those pollutants into the atmosphere. The traditional pollutant control method consists of a post-combustion flue gas treatment system comprising as many treatment devices as regulated pollutants. Currently, a post-treatment line commonly includes: a wet- or dry-FGD (Flue Gas Desulphurization) for SO_x removal, an ESP (Electrostatic Precipitator) for particulate removal and a SCR (Selective Catalytic Reduction) or SNCR (Selective Non-Catalytic Reduction) for NO_x control. Activated Carbon Injection (ACI) or other mercury control technology may be soon required for Hg removal. All these post-treatment technologies have a big drawback of being flue gas volume dependent. As more than 80% of the flue gas from a conventional air fired boiler consists of inert N_2, post-treatment of this flue gas is very expensive. It is thus easy to imagine that a nitrogen-free process like Oxycombustion would benefit from a highly reduced flue gas volume flow rate. Replacing the combustion air with pure oxygen in the combustion process results in five-fold flue gas volume decrease, leading to a much lower flue gas treatment costs. Also, some of the flue gas treatment devices such as SCR/SNCR for NO_x control may not be necessary because of very low levels of NO_x in Oxycombustion (see experimental results). Conventional air/coal fired power plant with a CO_2 capture system and a O_2-CO_2 coal power plant are schematically illustrated in Figure 1 and Figure 2 respectively.

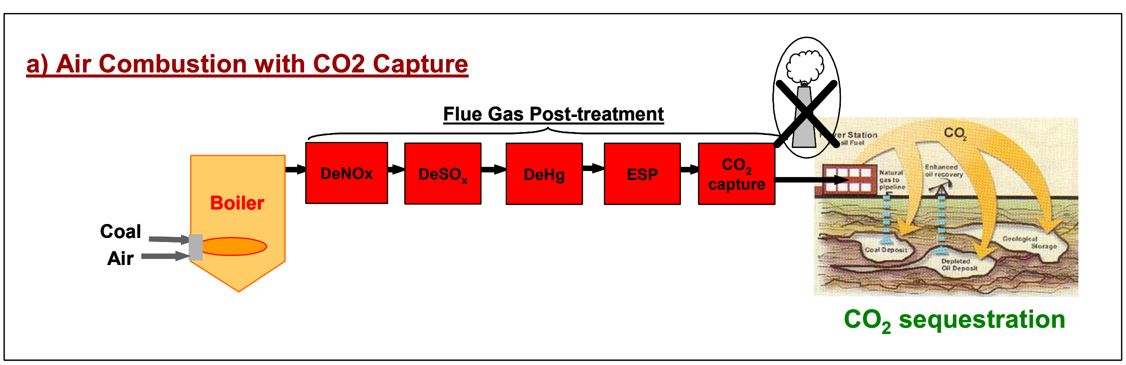

Figure 1: Scheme of air/coal fired power plant with CO2 Capture

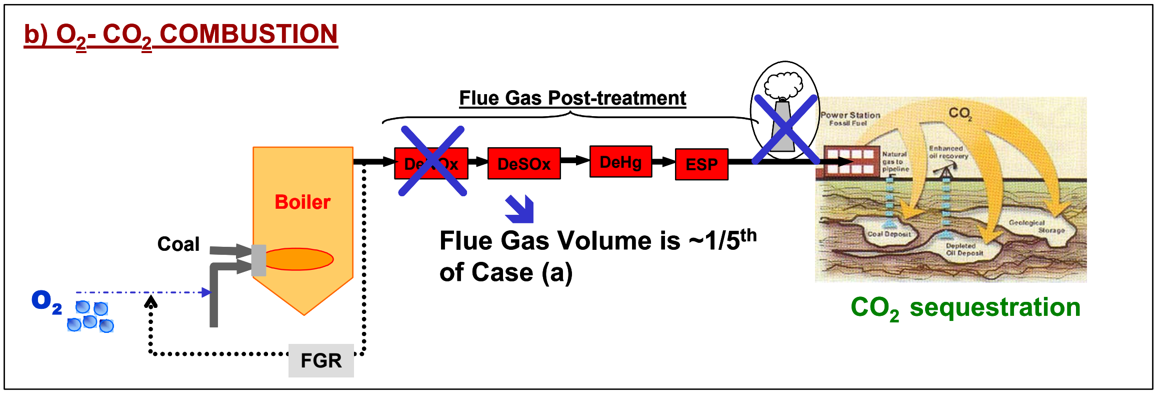

Figure 2: Scheme of O_2-CO_2/coal fired power plant

The O_2-CO_2 combustion technology offers a wide variety of alternatives. For a new power plant, the amount of FGR would be set to the minimum enabling compact boiler design, and thus resulting in significant boiler costs reduction. For a retrofit of an existing boiler, the flue gas is recirculated so that the characteristics of the boiler operation would remain similar to that of air fired case. In this paper, detailed techno-economic feasibility study of the O_2-CO_2 concept, its comparison to MEA system, and results of a pilot scale demonstration are presented.

TECHNO-ECONOMIC ANALYSIS

The techno-economic study of the CO_2 capture from conventional pulverized coal boiler with MEA and O_2-CO_2 combustion was performed by the Illinois State Geological Survey (ISGS) with inputs from American AirLiquide. Four different types of plant configurations are considered.

- Conventional air/coal fired boiler with NO CO_2 capture (PC)
- Conventional air/coal fired boiler with MEA for CO_2 capture (PC+MEA)
- O_2-CO_2 combustion with wet FGR (Wet OC)
- O_2-CO_2 combustion with dry FGR (Dry OC)

The difference between Dry OC and Wet OC process is that the moisture in the flue gas is removed before the flue gas is recirculated in Dry OC whereas in Wet OC the flue gas is recirculated without removing the moisture.

Process Simulation

A sub-critical steam cycle for power generation was assumed in all the above cases. CHEMCAD software was used for process simulation and calculation of mass and energy balances. The process was divided into four parts, coal combustion, steam generation, flue gas cleaning and either CO_2 capture by MEA or ASU for O_2 generation as listed below. Typical design and operating conditions of these processes were obtained from literature [2,3,4,5].

(1) Combustion

✓ Coal and Air (O_2) feed

- ✓ Boiler combustion
- ✓ Super heater, re-heater, economizer and air pre-heater
- ✓ Flue gas re-circulation (FGR)

(2) Steam turbine generator

- ✓ Steam turbine (HP, MP, LP)
- ✓ HRSG
- ✓ Cooling water system
- ✓ Feed water and miscellaneous systems (FWH 1-7, Deaerator)

(3) Flue gas cleaning

- ✓ ESP for Ash
- ✓ FGD (Lime Spray Dryer/LSD) for SO_x
- ✓ SCR for NOx
- ✓ ACI for Hg

(4) MEA process for CO_2 capture or ASU for O2 generation.

One important parameter that was fixed in the techno-economic assessment for all the cases was the gross power output, which is 533 MW_e. Many of the processes listed above consume significant amount of energy/electricity (auxiliary power), especially ASU or MEA, which impacts the net output of the power plant. Hence the following definitions are defined to evaluate the efficiency of the process.

Net Power Output = Gross Power Output – Auxiliary Power Input

Net plant efficiency = Net power output/total thermal input

Cost Assessment

Capital Cost

For assessing cost of the power generation technologies, DOE classified a power plant into 14 process areas. This study also follows the same classification for evaluating the costs of different components which are obtained by scaling DOE's reference plant [2,3]. Each process area is divided into sub-areas and many types of equipment may exist in each sub-area. Cost assessment is made at process level for the study.

1. Coal handling	6. HRSG, ducting and Stack	12. Improvements to site
2. Coal preparation & feed	7. Steam turbine generator	13. Buildings and structures
3. Feed water &misc.	8. Cooling water system	~~14. Gas turbine generator~~
4. PC boiler & accessories	9. Ash/Spent sorbent handling system	
5. Flue gas cleaning ESP, LSD, SCR, ACI	10. Accessory electric plant	
	11. Instrumentation & control	

Table 1: DOE's Process Areas Classification of a Power Plant

Gas turbine generator, which is a process area, is not considered for the study as only steam turbines are considered. Apart from the mentioned 13 process areas in Table 1, three more areas are considered which are specific to the study:

14. CO_2 separation (MEA)
15. ASU (O_2 production)
16. FGR

Operating and Maintenance Costs

Cost and expenses associated with operating and maintaining the plant include:

- ✓ Operating labor
- ✓ Administrative and support labor
- ✓ Maintenance labor and materials
- ✓ Consumables
- ✓ Fuel (Coal) cost

Operating and supportive labor costs are estimated on the basis of the number of operating jobs (OJ) required to operate the plant. The OJ data are not related to the plant size, but depend on the number of units under operation. Therefore, the representative OJ data of major plant areas in literature were used.

Annual cost of maintenance labor and materials is estimated as a percentage of the installed capital cost. The percentage varies widely, depending on the specific processing conditions and the type of design for each process area. From literature, the representative percentage was selected for each process area.

Consumables include:

- ✓ Water makeup for steam cycle and miscellaneous use
- ✓ Water treating chemicals
- ✓ Waste water treating chemicals
- ✓ L.P Steam
- ✓ Lime (for LSD)
- ✓ SCR catalyst
- ✓ Ammonia
- ✓ Activated carbon
- ✓ Amine

Based on the results from the process simulation study, the mass flows of the consumables listed above are calculated. Their costs were estimated based on unit market price.

As mentioned before, addition of MEA or ASU impacts the net power output of the plant. In order to take this impact into consideration, all the capital and operating costs are in \$/kW or \$/kWh based on net kW_e output. The capital costs are levelized over a period of 30 years assuming an inflation rate of 4.1%.

Cost of CO_2 Avoided

Cost of a CO_2 capture system is generally expressed in terms of either cost per ton of CO_2 removed or cost per ton of CO_2 avoided. For systems like MEA and ASU that are very energy intensive, cost per ton of CO_2 removed and avoided are very different. To take into account the reduced net power output resulting from CO_2 capture, the cost of CO_2 avoided is the most commonly used economic indicator. It will therefore be used in the present study. This indicator is calculated using the following formula [6].

$$\text{Cost of } CO_2 \text{ avoided (\$/ton)} = \frac{(\$/\text{kWh})_{\text{capture}} - (\$/\text{kWh})_{\text{reference}}}{(\text{tonCO}_2/\text{kWh})_{\text{reference}} - (\text{tonCO}_2/\text{kWh})_{\text{capture}}}$$

Key Assumptions

In summary, following are the key assumptions that are made in this study.

- ✓ Gross power output: 533 MWe
- ✓ O_2 purity: 99%
- ✓ Fuel: PRB coal
- ✓ Generation: sub-critical steam turbine
- ✓ All the $ represented here are 1999$
- ✓ Life of equipment: 30 years
- ✓ Inflation rate: 4.1%, discount rate: 9.25%
- ✓ MEA: Fluor Daniel Econamine FG process with 90% solvent efficiency
- ✓ LSD and SCR: 90% efficiency
- ✓ ACI: 80% efficiency
- ✓ Capacity factor: 70%

RESULTS AND DISCUSSION

The following parameters were calculated for four different plant configurations.

- ✓ Overall performances of the systems
- ✓ Flue gas compositions
- ✓ Capital costs in $/kWe
- ✓ Operating costs in $/kWe
- ✓ Electricity costs in mills/kWh
- ✓ CO_2 costs in terms of $/tonne of CO_2 avoided

Overall Performances of the plants

The overall performances of the four power plants configurations are presented in Table 2 and Figure 3.

	PC	**PC + MEA**	**Wet OC**	**Dry OC**
Steam Turbine Power (MWe)	533	434	533	533
ASU Power (MWe)	-	-	100	104
Other Aux. Power (MWe)	31	47	24	24
Net Power (MWe)	**501**	**388**	**408**	**405**
Net efficiency, HHV (%)	37.0%	28.6%	31.4%	29.9%

Table 2: Overall performances of the plants

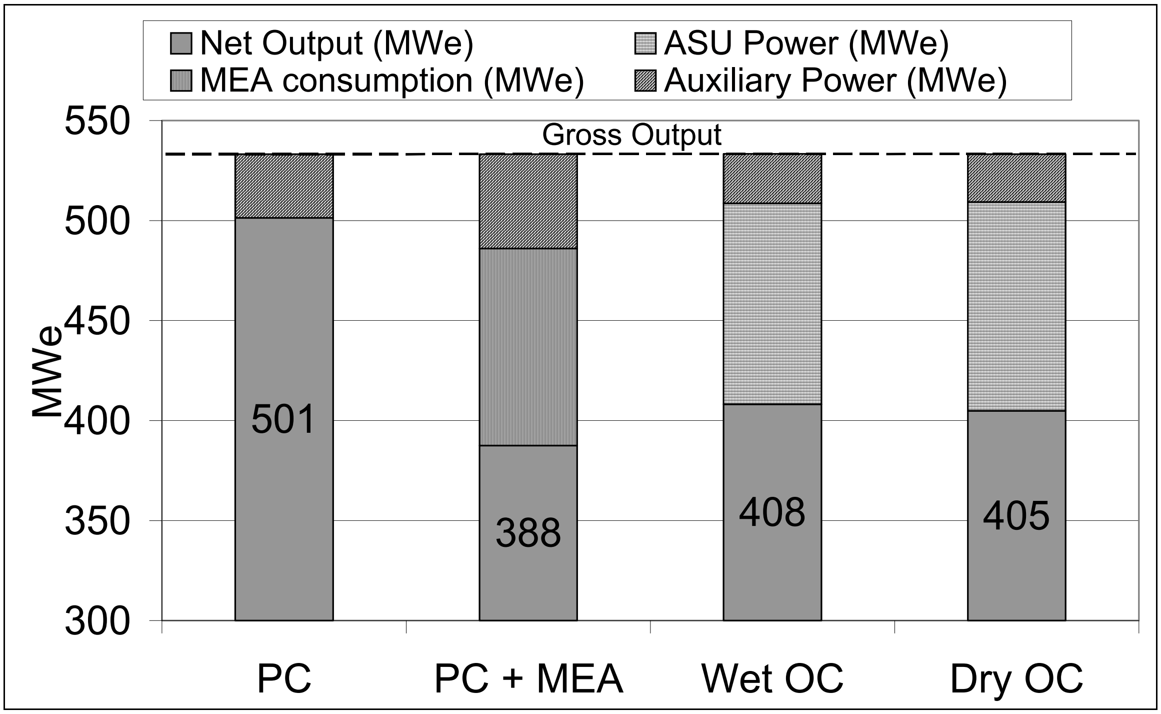

Figure 3: Overall performances of the plants

MEA process uses steam for amine regeneration, decreasing the steam available at the steam turbine, and thus the steam turbine gross output (434MWe instead of 533MWe on the conventional reference PC boiler, as shown in Table 2). This thermal power consumption of MEA is converted into electric power consumption on Figure 3 to enable easier comparison with OC processes. The OC Processes, wet or dry, require additional auxiliary power consumption to operate the ASU, reducing the net power output of the system by around 100MWe, while the gross power output is maintained at 533MWe.

Wet or Dry OC processes reduced the net power output from the existing plant by 18-19%. MEA process impacts the net power output a little bit more, leading to 22% of net power reduction. Based on the calculations performed on a 533MWe (gross) plant, the net power output from the plant equipped with MEA would be 20MWe lower than that of the O_2-CO_2 process. The effect of this decrease in net power output on the electricity costs and on the cost of CO_2 avoided is shown in the following graphs.

Flue Gas Volumes and Compositions

Figure 4 and Figure 5 show the flue gas compositions and volumes generated by the power plant configurations considered.

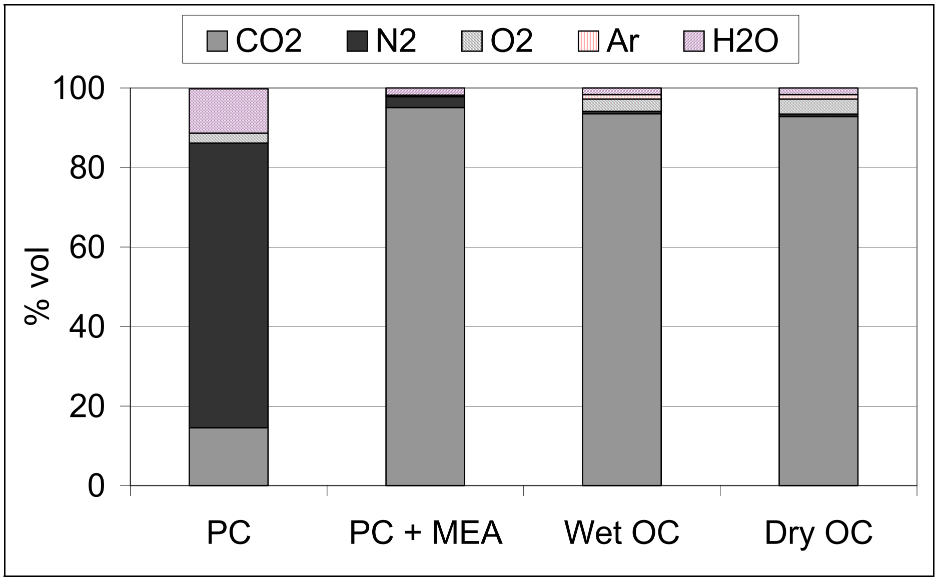

Figure 4: Flue gas compositions

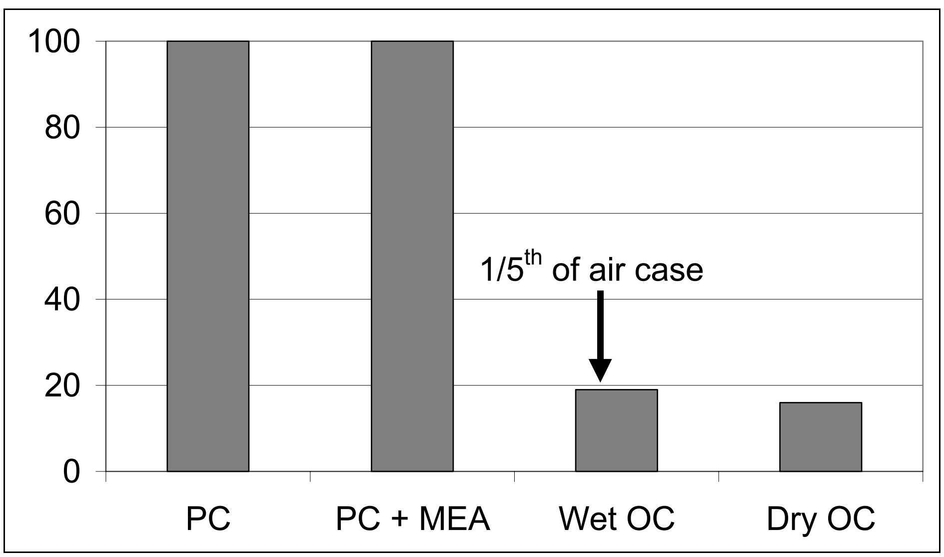

Figure 5: Flue gas volumes

In a conventional air/coal fired case, CO_2 is around 15% by volume of the flue gas, and most of the remaining volume is N_2. CO_2 produced by MEA is 95% by volume. As CO_2 is regenerated from aqueous solution, some amount of water is obtained with CO_2. In cases of O_2-CO_2 combustion, CO_2 obtained was also around 95% by considering the purity of oxygen as 99%. A water-cooled condenser was added in O_2-CO_2 combustion cases at the end of the process to remove the water in the CO_2 rich flue gas. Since this process cannot remove 100% of the moisture, there is 1-2% of water left. Further purifications might be needed for both MEA and O_2-CO_2 cases before the CO_2 can be transported for sequestration purposes. These could be easily done during the compression stages before the CO_2 is liquefied and transported. It is also evident from Figure 5 that the flue gas volume generated by O_2-CO_2 cases are less than 20% of the air case. It means that significant savings are apparent for flue gas cleaning to remove other pollutants. Because most of the water removed in condenser, the Dry OC case shows slightly lower flue gas volume than in the Wet OC case.

Capital, Operating and Maintenance (O&M) Costs

Capital costs and operating and maintenance costs normalized by net kWe output of different plant configurations are presented in Figure 6 and Figure 7 respectively.

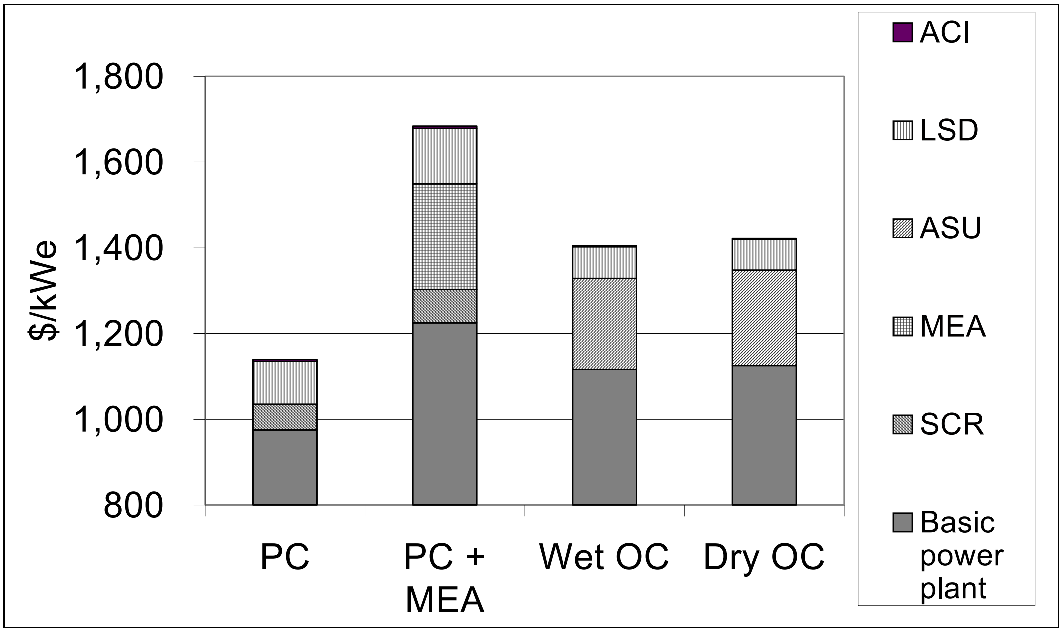

Figure 6: Capital costs of different plant configurations

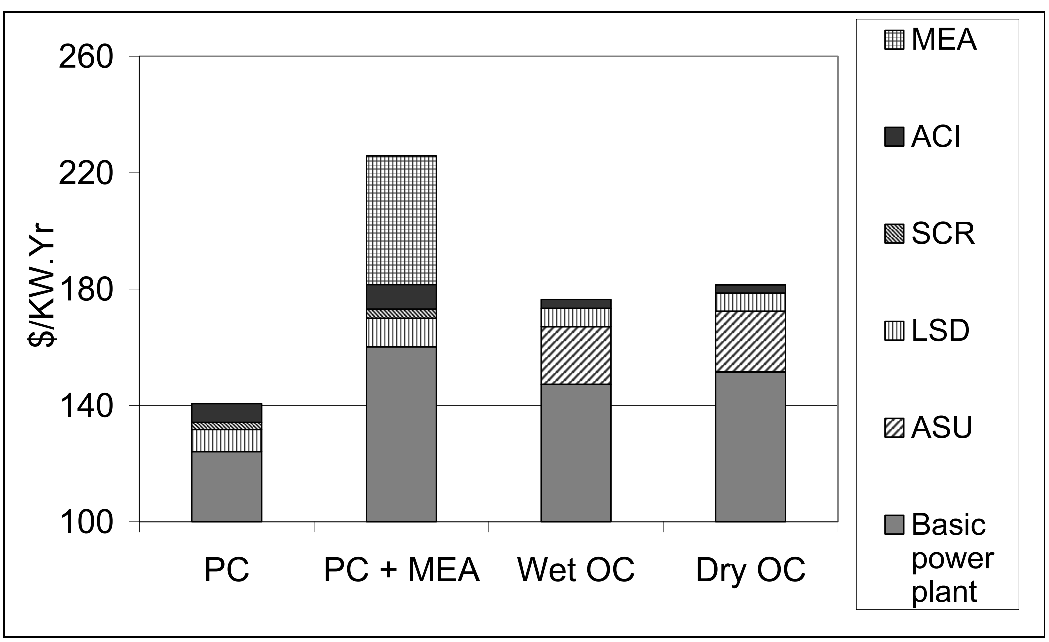

Figure 7: O&M Costs of different plant configurations

O_2-CO_2 plant shows significant cost reductions in both capital and O&M costs. The total plant capital costs of O_2-CO_2 cases are 15% to 20% cheaper and O&M costs are 20% cheaper than MEA case. This is due to the fact that MEA capital cost is slightly more expensive than ASU and operating cost of MEA is more than twice than that of ASU.

Cost of CO_2 avoided and electricity costs

Figure 8 shows the impact of addition of MEA and ASU units on the cost of electricity and CO_2 avoided.

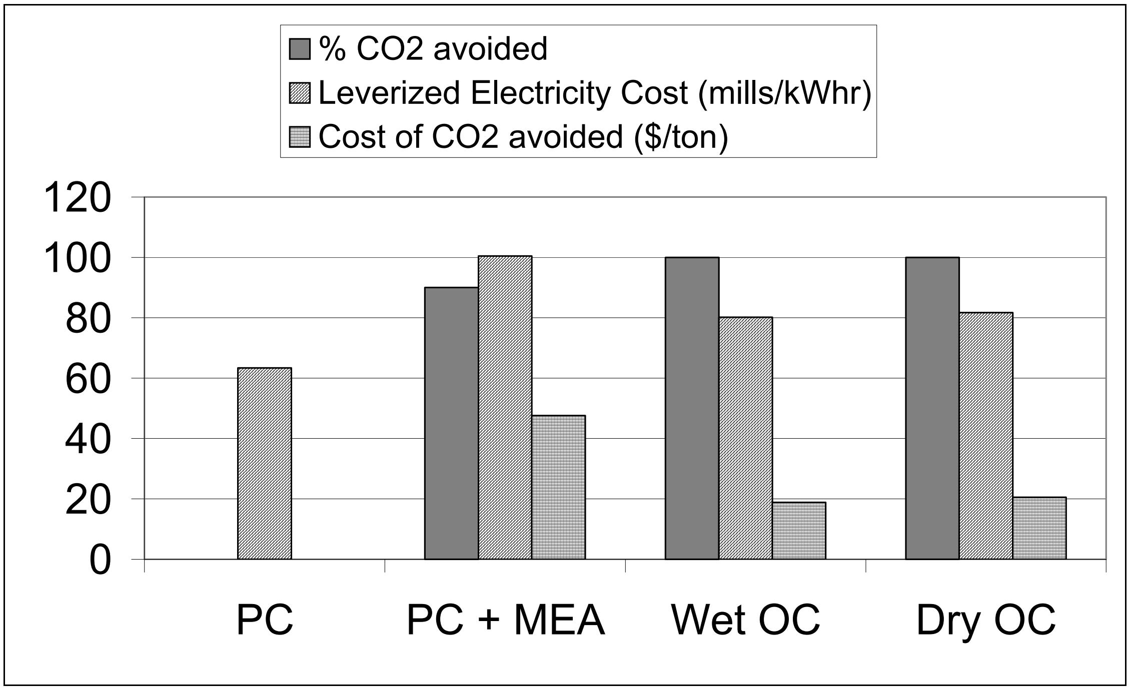

Figure 8: Electricity costs and CO2 avoidance costs

The levelized cost of the electricity increased by 65% for MEA case and by 33% for O_2-CO_2 case. This is also due to higher decrease in net power output of the MEA plant versus OC process.

CO_2 avoidance costs are compared in $/ton of CO_2 avoided which is the benchmark in this field. The CO_2 avoidance cost obtained by MEA plant was $47/ton whereas by O_2-CO_2 plants the cost was around $20/ton. CO_2 avoidance by O_2-CO_2 process is around 60% cheaper than MEA process. This significant difference is attributed to the fact that MEA is expensive to install and operate and also the absolute quantity of CO_2 avoided is 90% of total emissions for MEA and 99% for O_2-CO_2 case. Note that for both cases, the cost of CO_2 avoided does not include the cost of compression.

Cost of Retrofit Case

The retrofit case was also studied. Costs of existing components that need to be modified and new components that are added were considered. The modifications include different operating costs of flue gas cleaning systems due to different flue gas flow rates, addition of ASU and FGR system for O_2-CO_2 cases, and addition of MEA system to PC+MEA case. As there is no capital cost of the basic power plant involved, CO_2 avoidance cost can be lower than the new case provided there is considerable life remaining for the power plant. Without knowing the remaining life of the plant, it is not possible to evaluate the CO_2 avoidance cost in $/ton similar to the new case previously studied. Nevertheless, non-levelized costs of capital and O&M costs of different components are evaluated and are tabulated in Table 2 and Table 3.

	PC	PC +MEA	Wet OC	Dry OC
Net output, MWe	501	388	408	405
Total Plant Cost	$/kWe	$/kWe	$/kWe	$/kWe
ASU	-	-	212	223
MEA	-	247	-	-
ACI	4	5	2	2
SCR	60	78	-	-
LSD	100	129	74	72
Total	164	459	288	297

Table 3 Capital costs for retrofit cases

	PC	PC +MEA	Wet OC	Dry OC
O&M cost	mill/kWh	mill/kWh	mill/kWh	mill/kWh
1. Fixed O&M				
ASU & OC	-	-	2.99	3.04
MEA	-	3.54		
ACI	0.34	0.44	0.25	0.24
SCR	0.07	0.08	-	-
LSD	0.80	1.03	0.51	0.48
subtotal	1.20	5.10	3.75	3.76
2. Variable O&M				
ASU & OC	-	-	0.24	0.37
MEA	-	3.67	-	-
ACI	0.72	0.93	0.25	0.22
SCR	0.34	0.44	-	-
LSD	0.43	0.56	0.51	0.53
subtotal	1.49	5.60	1.01	1.12
Total O&M cost	**2.69**	**10.70**	**4.76**	**4.88**

Table 4: O&M costs for retrofit cases

From Table 3 and Table 4, it is evident that MEA process for CO_2 capture is very expensive compared to O_2-CO_2 processes. Capital costs for OC retrofit were 35% to 40% cheaper than MEA case. O_2-CO_2 system's O&M costs are more than 50% cheaper than MEA. These comparisons shows higher cost-efficiency of O_2-CO_2 method for CO_2 capture than MEA, even for the retrofit.

O_2-CO_2 DEMONSTRATION ON A PILOT SCALE BOILER

The demonstration part of the project was carried out in collaboration with The Babcock and Wilcox Company (B&W). The purpose of the demonstration is to prove the feasibility of O_2-CO_2 process and evaluate the overall process performances, including pollutant formation (NO_x especially) and heat transfer characteristics.

The pilot boiler, referred to as Small Boiler Simulator (SBS), is depicted in Figure 9. This 1.5MWth (5.10^6 Btu/hr) pilot-scale boiler simulates a utility boiler. Both the radiative (furnace) and the convective sections of the pilot are representative in terms of geometry and heat exchanger equipments of a utility boiler. The primary, Secondary and Tertiary Air (PA, SA, TA or overfire air OFA) of a conventional air-blown boiler are replaced by oxygen-enriched flue gas (O_2/CO_2), and are referred to as Primary, Secondary and Tertiary Oxidizers (PO, SO, TO).

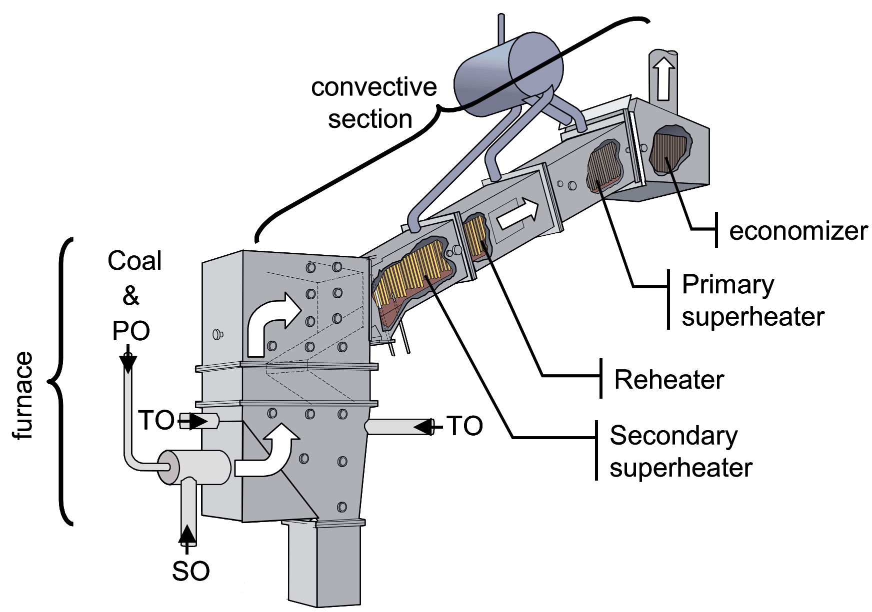

Figure 9: 1.5 MWth Pilot boiler

PO: Primary Oxidizer SO: Secondary Oxidizer TO: Tertiary Oxidizer

Tests were performed with a low-sulfur sub-bituminous coal with the following composition as received: 26.8 %moisture, 4.6% ash, 34.5% volatile. The ultimate dry analysis provides the following data: 72.21% carbon, 5% hydrogen, 0.92% nitrogen, 15.17% O and 0.41% sulfur. The heating value of the coal was 12,505 Btu/lb (dry basis).

The main experimental results are described in the following sections. More detailed tests data have been presented in [7].

The feasibility of switching a boiler operating with air to O_2-CO_2 process has been demonstrated. An operating procedure for smooth transition from air to O_2-CO_2 and then back to air combustion has been established. The possible control of oxygen content in the various oxidizer streams injected into the boiler offers a level of combustion optimization that does not exist in conventional boilers that are operated by only air.

Overall combustion characteristics of O_2-CO_2 process, such as temperature profile and flow pattern, were similar to that of air fired configuration. The amount of FGR was adjusted to keep the same flow rates and fluid dynamics inside the boiler. Stable flames, attached to the throat, were also obtained with the O_2-CO_2 process.

75% to 80% of the flue gas was recirculated. A corrosion resistant condenser was used on the recirculation line, to be in a dry recirculation configuration. The flue gas volume exiting through the stack was 80% lower than the volume of air case. Figure 10 displays the flue gas composition.

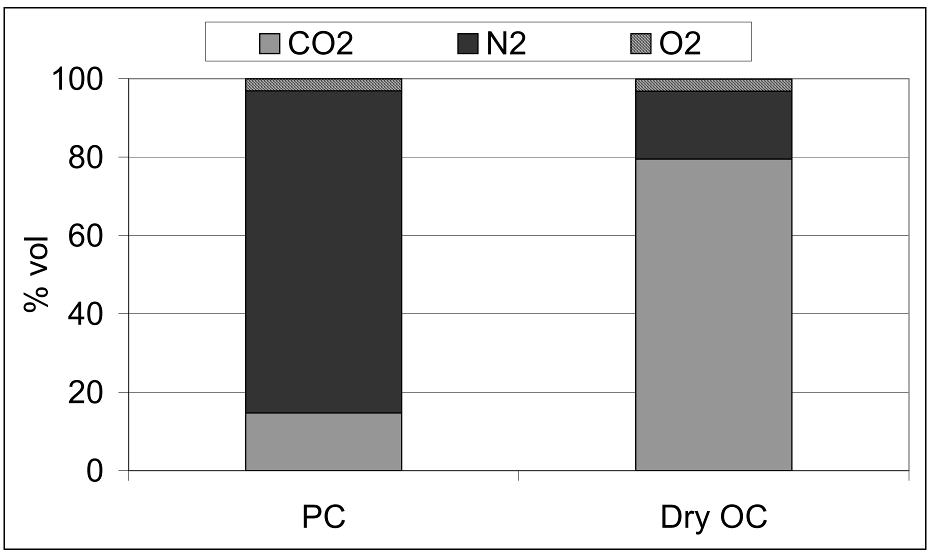

Figure 10: Flue gas compositions of experimental data

The flue gas compositions measured from the O_2-CO_2 tests was around 80% CO_2 by volume, 3% O_2 and 17% N_2. Since pure oxygen has been used for those tests, N_2 content in the flue gases are attributed to air-infiltration, due to some parts of the boiler operated under negative pressure. Approximately 5% of the stoichiometry originates from air infiltrations.

The air-infiltration was not considered in the techno-economic assessment presently and will be considered in the future work of the study. Various means to increase the concentration of the CO_2 in the flue gas are also being investigated.

The NO_x emissions were considerably lower in O_2-fired conditions than in air-baseline, the reduction rate averaging 70%. The baseline NO_x emission range was 0.22 to 0.26lb/10^6 Btu (with a low-NO_x burner) and dropped to 0.07 to 0.08 lb/10^6 Btu under oxycombustion conditions. NO_x emissions reduction is mainly due to the flue gas recirculation into the primary combustion zone. At high temperature and under reducing conditions, the recirculated NO_x are converted back into

N_2, via what is referred to as reburning process. Higher oxygen content in the primary combustion zone also results in higher local temperature. Such higher temperature in the reducing zone of the boiler increase the volatile yield and promotes the conversion of devolatilized fuel nitrogen to molecular nitrogen rather than NO_x [8]. Such low NOx levels justify the approach used in the economic study, where no NO_x control system is assumed for the O_2-CO_2 processes while an SCR is assumed on the air-fired case.

CONCLUSIONS

Detailed process calculations and economic analysis have been performed on MEA and O_2-CO_2 cases. The conclusions of this investigation are as follow:

- Both capture technologies impact the power plant performances and result in increased electricity prices. However, the impact seems to be much more significant using MEA process than using O_2-CO_2 process. The levelized cost of the electricity (6.3 cents/kWh) increases by 65% for MEA case (10 cents/kWh) and by only by 33% for O_2-CO_2 case (8 cents/kWh).
- The net power output is more affected in MEA case, with 22% net power reduction as compared to air-fired case, while only 18-19% net power reduction results from O_2-CO_2 process.
- The total plant capital cost of O_2-CO_2 cases is 15% to 20% cheaper and O&M cost is 20% cheaper than in MEA case.
- The cost of CO_2 avoided is around \$20/ton of CO_2 avoided for O_2-CO_2 case and \$47/ton for MEA case. Both of these costs do not include cost of compression.
- 90% of CO_2 emissions are avoided for MEA case and 99% for O_2-CO_2 case.

Experimental pilot-scale tests have been carried out. Detailed test results are reported in a separate paper. The main results have been highlighted in this paper, that provide validation or limitations of some assumptions made for the economics calculations.

- The tests have demonstrated some additional benefits of the O_2-CO_2 technology, in terms of NO_x reduction (70% from air-baseline, down to 0.08 lb/106 Btu) and overall plant efficiency. No NO_x control technology is then needed with O_2-CO_2 process.
- The tests also enable to identify some challenges to be investigated in more details. Air infiltration has been limited to 5% of the overall stoichiometry. However, it results in 17% nitrogen in the flue gases (80% CO_2). Therefore, the flue gas has to be further processed to increase the CO_2 purity from 80% to 95%-98%, as required for further sequestration or reuse. Various technologies are under investigation for purifying the flue gases. All of them will benefit from a reduced flue gases flowrate to be treated (70% less than in air-combustion).

It is concluded from this study that O_2-CO_2 combustion is a promising cost-effective technology for CO_2 capture. Removing most of the nitrogen prior to the combustion (oxycombustion) offers many advantages as compared to post-combustion separation of nitrogen in flue gases exiting an air-fired units. Further investigations are in progress to limit the air infiltration, and cost-effectively purify the flue gases to required CO_2 purities.

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